Kemper County Storage Complex

Injection Well 19-2

Mississippi Power Company

Injection Well Plugging Plan

40 CFR 146.92; 40 CFR 146.93(e)

Facility Information

Facility Name: Kemper County Storage Complex
Well Name: MPC 19-2

Facility Contact: Mississippi Power Company
Environmental Affairs
P.O. Box 4079
Gulfport, MS 39502-4079

Well Location: Kemper County, Mississippi
Latitude: 32.6130560
Longitude: -88.8061110

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List of Acronyms/Abbreviations

AoR	Area of Review
CCUS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
ECO_2S	Establishing An Early Carbon Dioxide Storage
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	feet
mg/L	milligrams per liter
MMt	Millions of Metric tons
MPC	Mississippi Power Company
PCC	Porters Creek Clay
PISC	Post-Injection Site Care
psi	Pounds per square inch
RCA	Routine Core Analysis
SS	Sub- Sea
TMS	Tuscaloosa Marine Shale
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Injection Well 1 Plugging Plan

The well plugging plan describes the process that Mississippi Power Company (MPC) will follow to plug the MPC 19-2 injection well in accordance with EPA's requirements 40 CFR 146.92 and 40 CFR 146.93(e), to ensure that the abandoned well maintains integrity and will not pose a threat to Underground Sources of Drinking Water (USDWs). Plugging activities will begin immediately following the cessation of CO_2 injection. MPC will notify the UIC Program Director in writing at least 60 days before plugging the injection well, as required in 40 CFR 146.92(c) Class VI Rule. Additionally, MPC will submit a well plugging report to the UIC Program Director within 60 days of plugging the injection wells [40 CFR 146.92(d)].

B. Injection Well Configuration

The proposed injection well is designed to accommodate constant-rate flow of the total mass of CO_2 that will be stored over the 30-year injection period. Accordingly, the injection tubing consists of a corrosion-resistant four and a half inch CR13 L-80 tubular set on a corrosion-resistant packer inside a nine and five-eighths inch chrome long string casing that is perforated in the injection interval (Paluxy Formation). The planned perforations will be set between 5,040 feet and 5,575 feet with 6 shots-per-foot and 60-degree phasing. **Figure 1** illustrates the proposed wellbore schematic, which depicts the size of the tubulars and completion design that will guide the type, quantity, and design of the cement operations. For more information on the injection well construction, including detailed tubular information and safety factors, please refer to the *Application Narrative*.

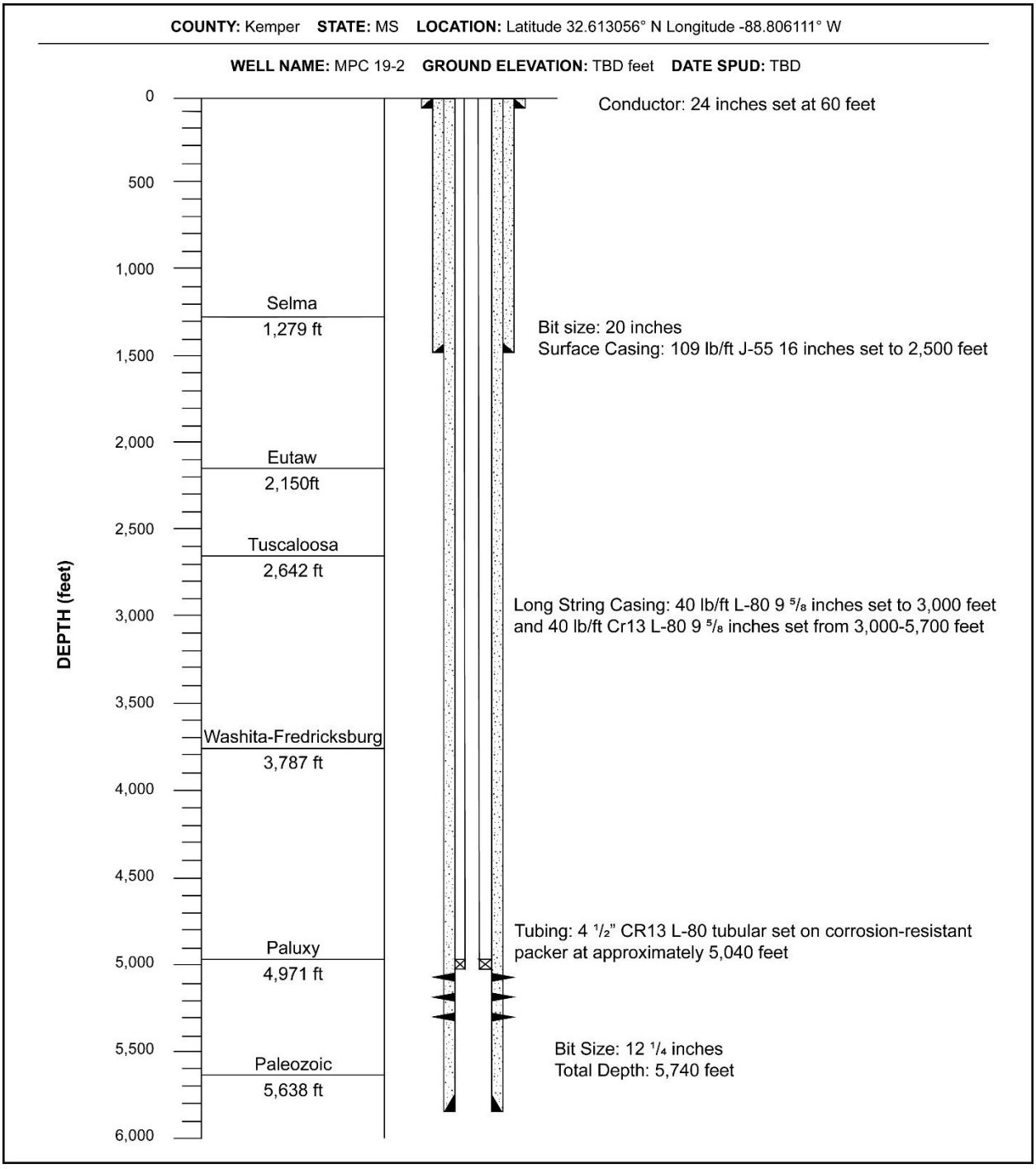

Figure 1: Proposed Injection Well Schematic

B.1 Injection Well Tests

B.1.a Tests or Measures for Determining Bottomhole Reservoir Pressure

Bottomhole pressure measurements will be recorded throughout the project. Pressure gauges will be placed in the injection tubing or within the long string casing adjacent to the injection zone. These pressure-measurement devices will allow for continuous, real-time, surface readout of the pressure data. Bottomhole reservoir pressure measurements will be obtained after the cessation of CO_2 injection to guide abandonment procedures. For more details on the monitoring strategy, please refer to the *Testing and Monitoring Plan*.

After the bottomhole pressure is determined, a buffered fluid (brine) will be used to flush and fill the well to maintain pressure control. The bottomhole pressure will be used to determine the proper brine weight necessary to stabilize the well. This data will also be used to determine the blend of cement to be used to plug the well (i.e., weight range of cement to prevent leak-off into formation or flowing of well, or to prevent premature setting and curing of the cement).

B.1.b Testing Method to Ensure External Mechanical Integrity

The mechanical integrity of the well must be demonstrated after CO_2 injection and prior to the plugging of the well to ensure no communication has been established between the injection zone and the USDWs or ground surface (per Section 146.92 of the EPA Class VI Regulations). Such integrity testing requires a temperature log, noise log, or an activated-oxygen log to be run in the well.

The project proposes to run a temperature log over the entire depth of the injection well. Data from the logging run will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration outside of the injection zone. This data will also be compared to data from the logs performed prior to injection of CO_2 into the well. Deviations between the temperature logs performed before and after the injection of CO_2 may indicate issues related to the integrity of the well casing or cement.

B.2 Plugging Plan Procedure

The EPA recommends that owners or operators emplace plugs: (1) above any production or injection zones; (2) above, below, and/or through each USDW; (3) at the bottom of intermediate and surface casings; (4) across any casing stubs (pulled casing sections); and (5) at the surface[1]. Mississippi Oil and Gas Board requirements state that in well plugging operations, cement plugs must be placed across the freshwater zone (approximately 1,200 ft to 1,300 ft), and across any casing shoes in the construction of the well[2]. The following procedure details the operations required to place a solid column of cement from the total depth of the well to the top of the casing string. This exceeds the recommendations/requirements of both the EPA's and the Mississippi Oil and Gas Board.

At the cessation of injection, the injection tubing and packer will be removed. Once this is complete, the balanced-plug placement method will be used to plug the well. If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well and the cement retainer method will be used for plugging the injection formation below the abandoned packer.

To further ensure no communication from the injection zone with the overlying USDWs or ground surface, the injection well casing will be plugged with cement. **Table 1** presents the intervals that will be plugged and the materials and methods that will be used to plug the intervals. The portion of the well corresponding to the injection zone will be plugged using CO_2-resistant cement with a retainer method. The cement retainer will be set 100 ft above the contact between the Paluxy Sandstone and the overlaying regional seal (**Figure 1**) and will be constructed of corrosion-resistant materials. Approximately 210 sacks of CO_2-resistant cement will be used to plug the injection interval. This volume of cement includes a 10 percent excess volume to be squeezed through the perforations into the Paluxy Sandstone.

[1] EPA, 2016. *Underground Injection Control Program Class VI Plugging, Post-Injection Site Care, and Site Closure Guidance*. EPA 816-R16-006.
[2] 26 Miss. Code R. § 2-1.28.B.2.a

Table 1: Intervals to Be Plugged and Materials/Methods Used

Description	*Top*	*Bottom*	*Type*	*Quantity*
Lift 1	5,200	5,700	EverCRETE	210 sacks
Lift 2	4,700	5,200	EverCRETE	190 sacks
Lift 3	4,200	4,700	EverCRETE	190 sacks
Lift 4	3,700	4,200	EverCRETE	190 sacks
Lift 5	3,200	3,700	EverCRETE	190 sacks
Lift 6	2,700	3,200	Class A	190 sacks
Lift 7	2,200	2,700	Class A	190 sacks
Lift 8	1,700	2,200	Class A	190 sacks
Lift 9	1,200	1,700	Class A	190 sacks
Lift 10	700	1,200	Class A	190 sacks
Lift 11	5	700	Class A	260 sacks

The pressure used to squeeze the cement will be determined from the bottomhole pressure data. However, the injection pressure of the cement will not exceed 90% of the fracture pressure of the Paluxy Sandstone. If it appears that the injection pressure will exceed 90% of the fracture pressure and the total amount of cement has not been pumped into the injection zone, cement pumping will cease, and the tubing will be removed from the cement retainer to allow the pressure to return to static conditions. After allowing the pressure to reduce, the tubing will be re-strung through the cement retainer and cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or plug.

Cementing operations will continue until the entire wellbore is cemented. Cement will be pumped in 500 ft lifts (190 sacks) using a balance method. This will ensure efficient cement placement and prevent tubing from sticking in the cement column. Error! Reference source not found. shows the details of the injection well after plugging and abandonment.

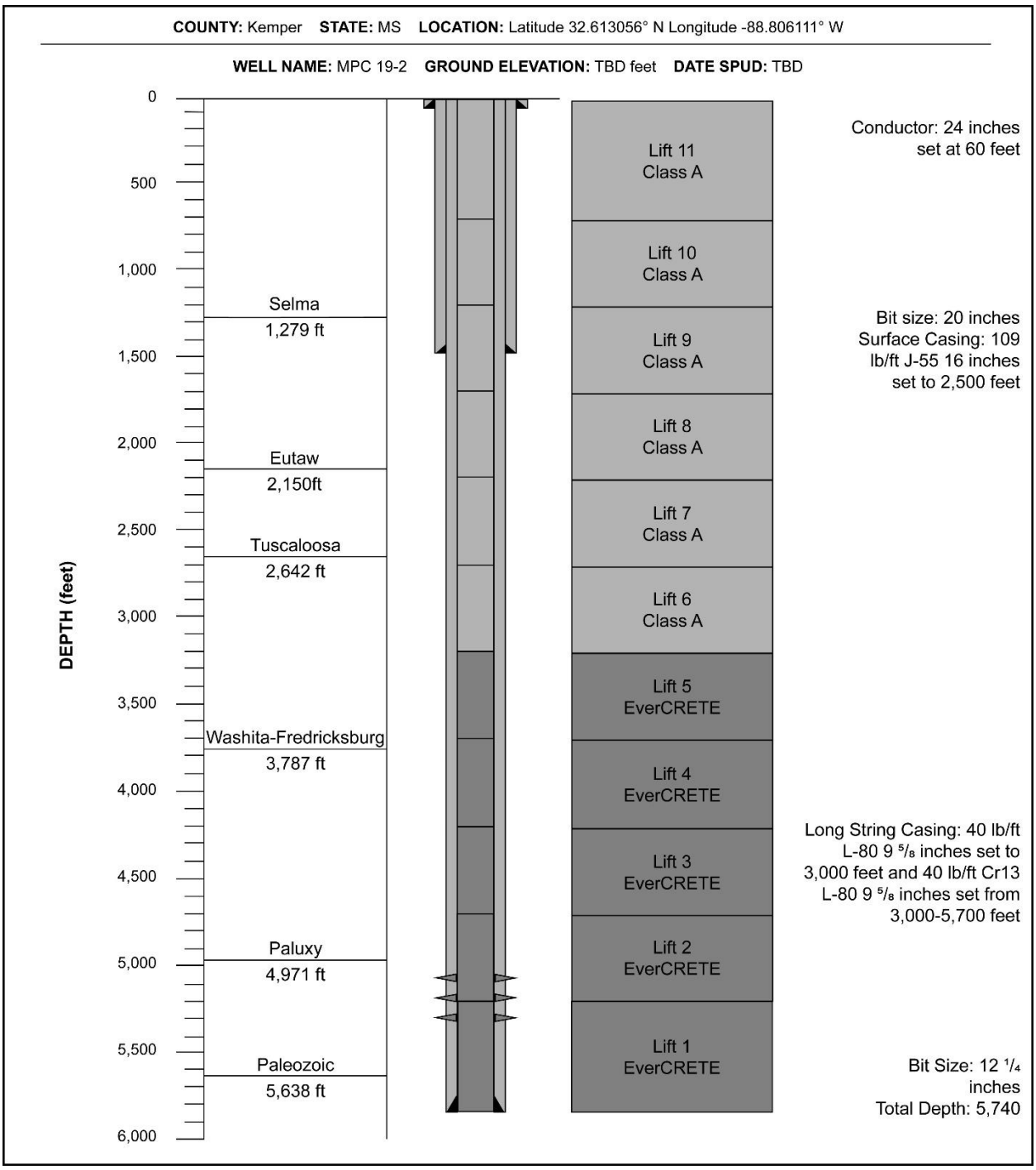

Figure 2: Diagram of the Injection Well After Plugging and Abandonment

After the final cement lift (Lift 11) has been completed, the casing sections will be cut off approximately 5 ft below ground surface, and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification number, the UIC Class VI permit number, and the date of plug and abandonment inscribed on it. Soil will be

backfilled around the well to bring the area around the well back to pre-installation grade. This area will then be planted with natural vegetation.

The methods and materials described to abandon the injection well are based upon the current understanding of the geology at the site and current well designs. If modifications are found to be required, the plans will be updated to reflect the latest geologic understanding and resultant well design. Updates to designs, materials, and methods will be described in the Notice of Intent to Plug submitted at least 60 days prior to the plugging of the well.